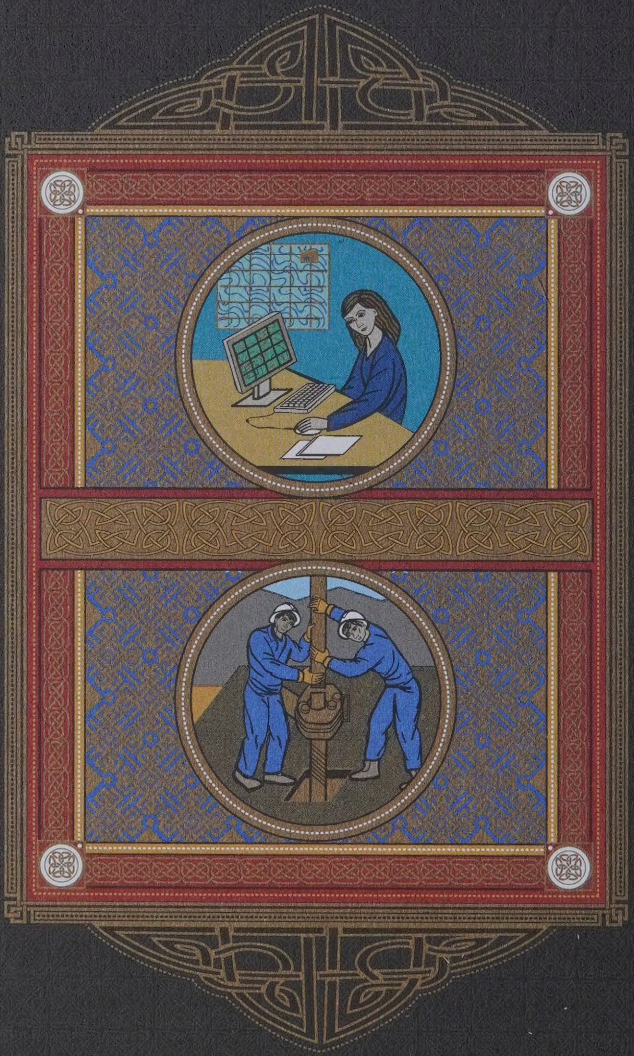
Look back 2,500 years, and you witness the origins of a historically remarkable people, the Celts. How did they endure when countless others did not? Historians point to a set of attitudes and abilities we might term the Celtic way.

Celtic Exploration Ltd. 2005 Annual Report

AMBITION

The Celts spread their culture and their languages over much of Western Europe. Celtic Exploration has established its oil and gas operations in Western Canada. Since our founding in 2002, Celtic has been adept at expanding production, net asset value per share and funds from operations per share.



DISCIPLINE

The Celts were more than fierce warriors. They were also master tacticians, capable of turning opportunity to advantage. At Celtic Exploration, we take a balanced approach to capital spending, and day-to-day operations thrive on clear leadership, close teamwork and financial discipline.

VISION

The Celtic culture produced a rich bounty of art and artifacts. With time, the greatness of these works is gaining recognition. Celtic Exploration chooses oil and gas assets with an eye to the future. We seek profitable production for today, and dramatic upside for tomorrow. This approach has secured an inventory of exceptional assets.

FLEXIBILITY

Not always was history kind to the Celts. They learned to adapt to changing circumstances, and so endured through many centuries. We at Celtic Exploration have purpose-built the company to thrive by building an asset base with high netbacks and a long reserve life.

his is the celtic way

Celtic Exploration Ltd. is a growth-oriented oil and gas exploration and production company based in Calgary, Alberta. Since commencing active oil and gas operations in 2002, the Company has rapidly grown its production base, resulting in record-high revenue and earnings in 2005. This annual report tells the story of a resourceful company with a team that is committed to creating shareholder value. This is the Celtic way.

($ thousands, unless otherwise indicated)	Three months ended December 31 2005	2004	Change	Twelve months ended December 31 2005	2004	Change
FINANCIAL						
Revenue, net of royalties	$ 26,647	$ 13,086	104%	$ 76,577	$ 50,260	52%
Funds from operations	$ 18,674	$ 9,559	95%	$ 56,969	$ 36,381	57%
Funds from operations per share						
Basic ($/share)	$ 0.65	$ 0.37	76%	$ 2.05	$ 1.41	45%
Diluted ($/share)	$ 0.62	$ 0.36	72%	$ 1.98	$ 1.37	45%
Net earnings	$ 7,062	$ 3,278	115%	$ 18,264	$ 11,501	59%
Earnings per share						
Basic ($/share)	$ 0.24	$ 0.13	85%	$ 0.66	$ 0.45	47%
Diluted ($/share)	$ 0.24	$ 0.12	100%	$ 0.64	$ 0.43	49%
Capital expenditures, net of dispositions	$ 41,490	$ 18,362	126%	$ 119,230	$ 55,145	116%
Total assets				$ 242,113	$ 135,984	78%
Bank debt				$ 41,700	$ 23,400	78%
Working capital deficiency, excluding bank debt				21,726	6,673	226%
Bank debt, net of working capital				$ 63,426	$ 30,073	111%
Shareholders' equity				$ 125,847	$ 76,436	65%
Common shares issued and outstanding (thousands)						
Basic				28,973	25,835	12%
Diluted				31,229	27,763	12%

	Three months ended December 31 2005	2004	Change	Twelve months ended December 31 2005	2004	Change
OPERATIONS						
Production						
Oil (bbls/d)	**2,915**	2,142	36%	**2,524**	2,283	11%
Natural gas (mcf/d)	**13,071**	8,292	58%	**11,396**	7,952	43%
Combined (BOE/d)	**5,094**	3,524	45%	**4,423**	3,608	23%
Production per million shares (BOE/d)	**176**	136	29%	**159**	140	14%
Realized sales prices, before financial derivatives						
Oil ($/bbl)	**$ 61.03**	$ 53.08	15%	**$ 62.02**	$ 48.71	27%
Natural gas ($/mcf)	**$ 12.48**	$ 7.13	75%	**$ 9.60**	$ 6.97	38%
Combined ($/BOE)	**$ 66.95**	$ 49.03	37%	**$ 60.11**	$ 46.15	30%
Operating netbacks, after financial derivatives						
Oil ($/bbl)	**$ 35.37**	$ 34.66	2%	**$ 36.79**	$ 31.88	15%
Natural gas ($/mcf)	**$ 8.38**	$ 4.48	87%	**$ 6.29**	$ 4.11	53%
Combined ($/BOE)	**$ 41.76**	$ 31.62	32%	**$ 37.20**	$ 29.20	27%
Drilling activity						
Total wells	**27**	19	42%	**100**	67	49%
Working interest wells	**15.3**	11.4	34%	**68.1**	41.5	64%
Success rate on working interest wells	**76%**	78%	-3%	**74%**	86%	-14%
Undeveloped land						
Gross acres				**261,346**	204,535	28%
Net acres				**164,239**	121,204	36%
Reserves						
Oil (mbbls)				**10,527**	6,739	56%
Natural gas (mmcf)				**47,992**	25,872	85%
Combined (mBOE)				**18,526**	11,051	68%
Reserve life index (years)				**10.0**	6.2	61%

The year 2005 proved to be Celtic's best yet for increasing shareholder value. With oil and gas reserves increasing by 68%, net asset value more than doubling to $11.53 per share and the corporate reserve life index increasing to 10 years, Celtic has truly grown into a substantial exploration and production company since commencing operations just over three years ago. Despite facing certain hurdles during the year, as a result of extremely wet weather conditions, getting production tied-in and keeping production operating through the wet summer, by the end of the year, Celtic was able to post a significant jump in production rates, exceeding its exit target rate of 6,400 barrels of oil equivalent per day, up considerably from approximately 3,800 barrels of oil equivalent per day at the end of 2004.

By the end of 2005, Celtic had increased its land position in its core areas, with year-over-year net undeveloped lands increasing by 36% to over 164,000 acres. Along with the increase in land holdings, Celtic was able to add significantly to its drilling inventory by proving up several new prospects and tying up other new untested opportunities that will be further evaluated through the drill bit in 2006.

The majority of reserve and production additions during the year came from drilling 100 gross (68.1 net) wells, with a success rate of 74%. Celtic's target was to add reserves on a proved-plus-probable basis below $15.00 per barrel of oil equivalent. The Company achieved its objective with finding, development and acquisition costs of $14.64 per barrel of oil equivalent, resulting in a recycle ratio of 2.5 times. Moreover, Celtic's reserve life index of 10 years was a 61% improvement from the previous year. Considering the state of the industry, with services getting more difficult to access and the overall cost of services rising, these results should stack up very well when compared with our peers.

Celtic expects to deliver continued growth again in 2006, with services being secured well in advance of the busy winter drilling season. The Company plans to drill over 100 wells in 2006, with a total capital expenditure budget of $120 million. This program will be funded from funds from operations estimated at $107.7 million and the balance from Celtic's unused bank lines of credit. The Company expects production in 2006 to average between 7,200 and 7,600 barrels of oil equivalent per day, with 55% being oil and liquids. Although historically high commodity prices were seen at the end of 2005, Celtic's 2006 forecast is premised on an average US$8.50 per mmbtu NYMEX natural gas price ($9.00 per mcf at the wellhead) and an average US$61.00 per barrel WTI oil price. These prices were then underpinned with approximately 46% of forecasted production being fixed for the year. Approximately 9.5 million cubic feet per day of Celtic's natural gas sales have been fixed at an average price of $11.55 per mcf for the year and 1,800 barrels per day of the Company's oil sales have been hedged using a combination of fixed price swaps and collars, which guarantee a minimum floor price of US$60.00 per barrel and maximums of $61.20, $65.20 and $70.10 per barrel.

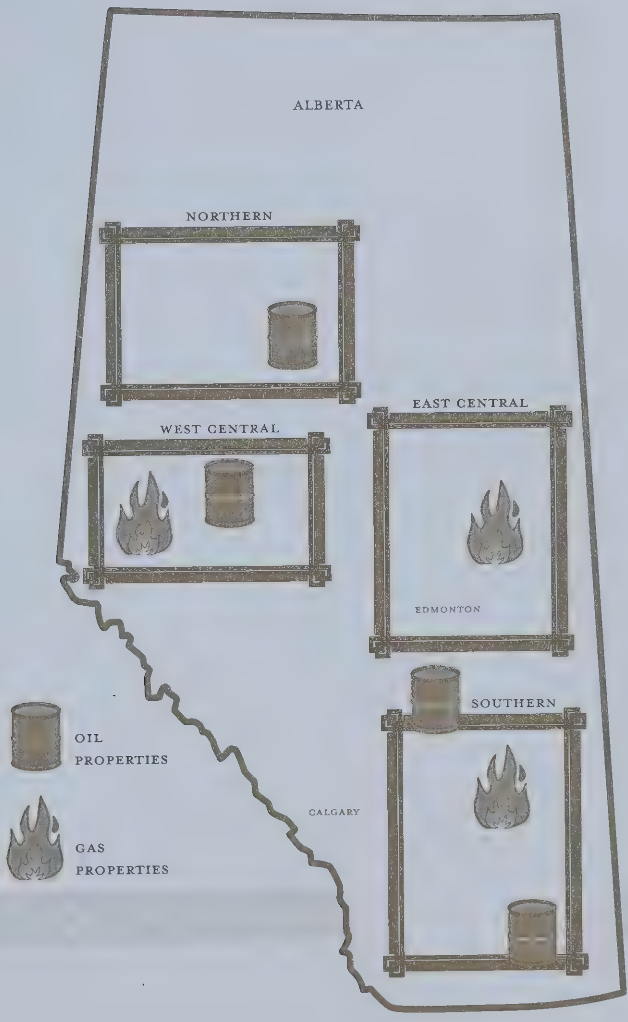
With Celtic's rich land and drilling inventory, proactive service procurement strategy and fixed commodity sales prices on just under half of its forecasted production, the Company has a good start to what should be another successful year in 2006.

DAVID J. WILSON

President and Chief Executive Officer

February 27, 2006

CORE AREAS



ALBERTA
NORTHERN
WEST CENTRAL
EAST CENTRAL
EDMONTON
SOUTHERN
CALGARY
OIL
PROPERTIES
GAS
PROPERTIES

PRODUCTION
(BOE/d)

INTRODUCTION

The Company was incorporated on April 16, 2002 as Desco Exploration Ltd. and completed its initial public offering on June 27, 2002. On September 30, 2002, the Company changed its name to Celtic Exploration Ltd. ("Celtic" or the "Company"). Celtic's head office is based in Calgary, Alberta, Canada. Common shares of the Company are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the symbol "CLT."

The following management's discussion and analysis ("MD&A") should be read in conjunction with the Company's audited financial statements and related notes for the year ended December 31, 2005. This MD&A is effective February 27, 2006. The accompanying financial statements of Celtic have been prepared by management and approved by the Company's Audit Committee and Board of Directors. These financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Additional information relating to Celtic can be found on the SEDAR website at www.sedar.com.

Non-GAAP Financial Measurements This document contains the terms "funds from operations" and "operating netbacks" which do not have a standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Funds from operations and operating netbacks are used by Celtic as key measures of performance. Funds from operations and operating netbacks are not intended to represent operating profits nor should they be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. The reconciliation between net earnings and funds from operations can be found in the statement of cash flows included in the audited financial statements. Operating netbacks are determined by deducting royalties, production expenses and transportation and selling expenses from oil and gas sales revenue. The Company calculates funds from operations per share using the same method and shares outstanding which are used in the determination of earnings per share.

Other Measurements All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. References to oil in this discussion include crude oil and natural gas liquids ("NGLs"). NGLs include condensate, propane, butane and ethane.

Critical Accounting Estimates Management is required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company.

Capitalized costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved reserves.

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Liability recognition for asset retirement obligations associated with oil and gas well sites and facilities are determined using estimated costs discounted based on the estimated life of the asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. Over time, the liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation.

In order to recognize stock-based compensation expense, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on Celtic's financial statements.

Changes in Accounting Policies and Practices Details outlining Celtic's accounting policies are contained in the notes to the financial statements. There were no changes in the Company's accounting policies and practices in 2005, compared to the previous year.

PRODUCTION PER MILLION SHARES
(BOE/d)

GROWTH STRATEGY

Celtic growth strategy is dual-pronged. The Company seeks to acquire assets with exploitation potential and, at the same time, implements its full-cycle exploration program. This strategy has proved successful to date as is evidenced by Celtic's rapid growth since commencing active oil and gas operations in September 2002. To complement this strategy, the Company has assembled a team of experienced and qualified personnel and is well positioned financially to act quickly on new opportunities. Celtic believes that its growth strategy will continue to increase funds from operations per share, net asset value per share and production per share.

RESULTS OF OPERATIONS

2005 Highlights The year ended December 31, 2005 was another successful year in the execution of the Company's growth strategy. Highlights for 2005 are as follows:

- Completed the acquisition of complementary oil and gas properties in the Swan Hills/Virginia Hills area of west central Alberta for approximately $2.5 million and subsequently expanded the Company's land position in the area through Crown land acquisitions and by drilling earning wells pursuant to various farm-in agreements;
- Generated gross proceeds of $30.7 million by completing an equity financing that resulted in the issuance of 3.0 million common shares at a price of $10.25 per share;
- Drilled 100 (68.1 net working interest) wells during the year resulting in 41 (29.5 net) oil wells, 30 (19.8 net) natural gas wells and 4 (1.0 net) coal bed methane wells, for an overall success rate, based on net wells, of 74%;
- Reported earnings per share (diluted) of $0.64, an increase of 49% compared to $0.43 in 2004;
- Reported funds from operations per share (diluted) of $1.98, an increase of 45% from $1.37 in the previous year;
- Generated an average operating netback of $37.20 per BOE, up 27% from $29.20 per BOE in 2004;
- Increased average daily production by 23% to 4,423 BOE per day, up from 3,608 BOE per day in 2004 and achieved daily average production per million shares of 159 BOE per day, up 14% in 2005 compared to 140 BOE per day in the previous year;
- Increased proved plus probable reserves by 68% to 18.5 million BOE, up from 11.1 million BOE at December 31, 2004 and increased net undeveloped land holdings by 36% to 164,239 acres compared to 121,204 acres at December 31, 2004; and
- Improved the Company's net asset value per share at year-end to $11.53, an increase of 108% compared to $5.55 at December 31, 2004.

Production Oil and gas production in 2005 increased 23% to average 4,423 BOE per day compared to 3,608 BOE per day in 2004. Average production in the fourth quarter of 2005 was 5,094 BOE per day. Production per million shares outstanding in 2005 averaged 159 BOE per day, up 14% from 140 BOE per day in 2004. The following table provides a summary of daily average production:

Production Summary

Years ended December 31	2005	2004	2003
Oil (bbls/d)	**2,524**	2,283	1,055
Natural gas (mcf/d)	**11,396**	7,952	5,318
Combined (BOE/d)	**4,423**	3,608	1,941
Production per million shares (BOE/d)	**159**	140	87

Celtic's production is entirely based in Alberta and is divided into four core areas. In Southern Alberta, the Company's primary natural gas producing properties are located at Drumheller, Michichi and Richdale and its primary oil producing properties are located at Princess, Bantry and Bow Island. In East Central Alberta, the principal producing asset is a shallow natural gas property at Ashmont. In Northern Alberta, the Company produces mainly light oil from Ogston, Otter and Utikuma Lake. In West Central Alberta, Celtic has both natural gas and light oil production at Fox Creek, Morse River/Swan Hills and Kakwa/Chime. The following table provides a summary of daily average production in each core area:

Principal Producing Properties

(BOE/d) Years ended December 31	2005	2004	2003
Southern Alberta	**1,865**	1,475	1,186
West Central Alberta	**1,530**	1,114	174
Northern Alberta	**638**	630	254
East Central Alberta	**390**	389	327
Total	**4,423**	3,608	1,941

OIL NETBACK
($/bbl)

Revenue Revenue, after royalties, for the year ended December 31, 2005 was $76.6 million, an increase of 52% compared to $50.3 million in the previous year. For the three months ended December 31, 2005, revenue, after royalties, was $26.6 million, up 104% from the fourth quarter of 2004. The breakdown of revenue is summarized in the following table:

Revenue

Years ended December 31	2005		2004		2003	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Oil revenue	54,277	62.06	40,775	48.79	14,132	36.62
Natural gas revenue	40,031	57.78	20,281	41.82	13,195	40.80
Royalties	(17,731)	(10.98)	(10,796)	(8.17)	(4,897)	(6.91)
Revenue	76,577	47.43	50,260	38.04	22,430	31.65

The combined average product price received for oil and gas sales for the year ended December 31, 2005 was $60.11 per BOE, an increase of 30% compared to the previous year. For the three months ended December 31, 2005, the average product price received was $66.95 per BOE, up 37% from the average price received in the fourth quarter of 2004.

Oil Operations Oil production for the year ended December 31, 2005 averaged 2,524 bbls per day, an increase of 11% compared to the previous year. For the three months ended December 31, 2005, average oil production was 2,915 bbls per day, up 36% from the fourth quarter of 2004.

The average price received for oil sales for the year ended December 31, 2005 was $62.02 per bbl, an increase of 27% compared to the previous year. For the three months ended December 31, 2005, the average oil price received was $61.03 per bbl, up 15% from the average price received in the fourth quarter of 2004.

For the year ended December 31, 2005, average oil royalties were 17.0% of sales. In the previous year, average oil royalties were 16.8% of sales. Celtic participated in various royalty incentive programs in 2005 and 2004, resulting in lower royalties for both years.

Transportation and selling expenses for oil production in 2005 averaged $0.61 per bbl compared to $0.46 per bbl in 2004. The higher per unit cost in 2005 reflects the larger percentage of oil production that was trucked in contrast to the previous year.

For the year ended December 31, 2005, production expenses were $10.93 per bbl. In the previous year, production expenses were $8.28 per bbl. The higher per unit production expense in 2005 reflects the broad-based increase in service costs in the oil services industry and higher electricity prices.

The breakdown of oil netbacks is summarized in the following table:

Oil Netback

Years ended December 31	2005		2004		2003	
	bbls/d	$/bbl	bbls/d	$/bbl	bbls/d	$/bbl
Daily average production	**2,524**		2,283		1,055	
Sales price		**62.02**		48.71		36.60
Gain (loss) on financial derivatives		**(3.15)**		–		–
Other oil revenue		**0.04**		0.08		0.02
Royalties		**(10.58)**		(8.17)		(6.23)
Transportation and selling expense		**(0.61)**		(0.46)		(0.84)
Production expense		**(10.93)**		(8.28)		(7.33)
Oil netback		**36.79**		31.88		22.22

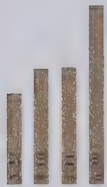
Natural Gas Operations Natural gas production for the year ended December 31, 2005 averaged 11,396 mcf per day, an increase of 43% compared to the previous year. For the three months ended December 31, 2005, average natural gas production was 13,071 mcf per day, up 58% from the fourth quarter of 2004.

The average price received for natural gas sales for the year ended December 31, 2005 was $9.60 per mcf, an increase of 38% compared to the previous year. For the three months ended December 31, 2005, the average natural gas price received was $12.48 per mcf, up 75% from the average price received in the fourth quarter of 2004.

For the year ended December 31, 2005, average natural gas royalties were 20.0% of sales, compared to 19.5% in the previous year.

Transportation and selling expenses for the year ended December 31, 2005 were $0.15 per mcf, an improvement of 21% compared to $0.19 per mcf for the previous year.

For the year ended December 31, 2005, production expenses improved to $1.27 per mcf. In the previous year, production expenses were $1.31 per mcf.



NATURAL GAS NETBACK
($/mcf)

The breakdown of natural gas netbacks is summarized in the following table:

Natural Gas Netback

Years ended December 31	2005		2004		2003	
	mcf/d	$/mcf	mcf/d	$/mcf	mcf/d	$/mcf
Daily average production	11,396		7,952		5,318	
Sales price		9.60		6.97		6.80
Other natural gas revenue		0.03		0.00		0.00
Royalties		(1.92)		(1.36)		(1.29)
Transportation and selling expense		(0.15)		(0.19)		(0.19)
Production expense		(1.27)		(1.31)		(1.22)
Natural gas netback		6.29		4.11		4.10

Interest Expense The Company has a demand revolving credit facility with a Canadian chartered bank that provides borrowings with interest payable monthly. Borrowing utilizing Bankers' Acceptances is also available under the facility. Interest expense for the year was $1.1 million at an average rate of 4.2% compared to $0.5 million at an average rate of 4.2% in 2004.

Interest Expense

Years ended December 31	2005		2004		2003	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Interest expense	1,079	0.67	540	0.41	221	0.31
Average debt outstanding	25,666		12,943		4,340	
Average interest rate (%)	4.2%		4.2%		5.1%	

General and Administrative Expenses General and administrative expenses for the year ended December 31, 2005 were $1.9 million or $1.19 per BOE. General and administrative expenses are reduced by overhead recovered on Company-operated properties. In addition, salaries relating to geological and geophysical personnel are capitalized. The following table provides a breakdown of general and administrative expenses:

General and Administrative Expenses

Years ended December 31	2005		2004		2003	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Gross general and administrative expenses	4,707	2.92	3,170	2.40	1,772	2.50
Overhead recoveries	(2,339)	(1.45)	(1,227)	(0.93)	(771)	(1.09)
Capitalized overhead	(459)	(0.28)	(393)	(0.30)	(127)	(0.18)
General and administrative expenses	1,909	1.19	1,550	1.17	874	1.23

Employees

At December 31	2005	2004	2003
Head office	29	24	19
Field operations	6	4	2
Total employees	35	28	21

Stock-based Compensation Expense For the year ended December 31, 2005, stock-based compensation expense was $0.8 million, compared to $0.6 million in 2004. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions shown in the following table:

Stock-based Compensation Expense

Years ended December 31	2005		2004		2003	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Stock-based compensation expense	844	0.52	605	0.46	168	0.24
Weighted average assumptions for stock options granted:						
Risk-free interest rate	3.37%		3.19%		3.06%	
Expected life in years	3.0		3.0		3.0	
Expected volatility	32%		34%		37%	
Expected dividend yield	–		–		–	

PRODUCTION
EXPENSE
($/BOE)

Depletion, Depreciation and Amortization The Company follows the full-cost method of accounting whereby all costs relating to the exploration and development of oil and gas reserves are capitalized. These capitalized costs, along with estimated future capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved oil and gas reserves as evaluated by independent engineers. Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25%. Estimated future costs relating to asset retirement obligations are provided for on a unit-of-production basis and the provision is included in depletion, depreciation and amortization.

Depletion, depreciation and amortization expense for the period ended December 31, 2005 was $28.9 million or $17.89 per BOE. The following table provides a summary of the amounts included in depletion, depreciation and amortization:

Depletion, Depreciation and Amortization

Years ended December 31	2005		2004		2003	
	$ thousands	$/BOE	$ thousands	$/BOE	$ thousands	$/BOE
Depletion – intangible P&NG assets	**21,955**	**13.61**	15,070	11.41	7,555	10.65
Depreciation – tangible P&NG assets	**6,374**	**3.95**	4,060	3.07	1,889	2.67
Depreciation – other assets	**100**	**0.06**	77	0.06	42	0.06
Amortization – asset retirement costs	**434**	**0.27**	350	0.26	209	0.29
Depletion, depreciation and amortization	**28,863**	**17.89**	19,557	14.80	9,695	13.67

Ceiling Test The Company performed a ceiling test calculation at December 31, 2005 in accordance with the CICA full-cost accounting guidelines. As a result of the calculation, Celtic was not required to record an impairment loss. In addition, based on the calculation conducted at December 31, 2004, there was no impairment loss required. The forecasted future oil and gas prices for the next 10 years used in the ceiling test evaluation of the Company's proved reserves as at December 31, 2005 are included in the notes to the financial statements.

Taxes For the year ended December 31, 2005, Celtic provided for a provision for future income taxes in the amount of $8.8 million. This amount differs from the expected provision for income taxes of $10.2 million based on the statutory combined income tax rate of 37.62% due to the differences between the resource allowance

deduction and non-deductible Crown charges and non-taxable provincial tax credits ("Alberta Royalty Tax Credit" or "ARTC") and the recognition of a benefit of $0.8 million related to substantively enacted changes to the federal income tax rate and resource-related deductions from income. These changes, which will be phased in over the next two years, will result in a lower corporate income tax rate, provide for the deduction of Crown royalties and eliminate the resource allowance deduction. An analysis of the income tax provision is included in the notes to the financial statements.

Capital tax for the year ended December 31, 2005 was $0.1 million. This tax is with respect to the federal Large Corporations Tax ("LCT") or Part I.3 Tax and is calculated based on the Company's taxable capital base including debt and shareholders' equity. The LCT is being phased out over the next three years, with the LCT rate reducing from 0.175% effective January 1, 2005 to 0.125%, 0.0625% and nil effective January 1, 2006, January 1, 2007 and January 1, 2008, respectively. The allowable capital deduction is currently $50.0 million.

At December 31, 2005, Celtic had unused income tax deductions available of approximately $141.6 million. A summary of these deductions with corresponding rates of deductibility is shown in the table below:

Income Tax Deductions

At December 31	2005		2004		2003	
	$ thousands	Deduction rate	$ thousands	Deduction rate	$ thousands	Deduction rate
Canadian oil and gas property expense (COGPE)	30,700	10%	23,707	10%	23,679	10%
Canadian development expense (CDE)	47,000	30%	23,634	30%	10,713	30%
Canadian exploration expense (CEE)	22,200	100%	5,816	100%	5,770	100%
Undepreciated capital cost (UCC)	39,600	4% to 30%	21,779	4% to 30%	12,910	4% to 30%
Share issue costs	2,100	5 years	1,253	5 years	1,693	5 years
Income tax deductions	141,600		76,189		54,765	

Net Earnings and Funds from Operations Net earnings for the year ended December 31, 2005 was $18.3 million ($0.66 per share, basic and $0.64 per share, diluted). During the same period, funds from operations were $57.0 million ($2.05 per share, basic and $1.98 per share, diluted).

CAPITAL EXPENDITURES
($MM)

The following table provides detailed unit statistics on a barrel of oil equivalent basis:

Unit Statistics

Years ended December 31	2005		2004		2003	
	boe/d	$/boe	boe/d	$/boe	boe/d	$/boe
Daily average production	4,423		3,608		1,941	
Sales price		60.11		46.15		38.51
Gain (loss) on financial derivatives		(1.80)		–		–
Other oil and gas revenue		0.10		0.06		0.05
Royalties, net of ARTC		(10.98)		(8.17)		(6.91)
Transportation and selling expense		(0.72)		(0.72)		(0.96)
Production expense		(9.51)		(8.12)		(7.32)
Operating netback		37.20		29.20		23.37
General and administrative expense		(1.18)		(1.17)		(1.23)
Interest expense		(0.67)		(0.41)		(0.31)
Capital tax		(0.06)		(0.08)		(0.22)
Funds from operations		35.29		27.54		21.61
Stock-based compensation expense		(0.52)		(0.46)		(0.24)
Depletion, depreciation and amortization		(17.89)		(14.80)		(13.67)
Accretion of asset retirement obligation		(0.13)		(0.15)		(0.13)
Future income tax		(5.44)		(3.42)		(0.94)
Net earnings		11.31		8.71		6.63

INVESTMENT AND INVESTMENT EFFICIENCIES

Capital Expenditures Celtic is committed to future growth through its strategy to augment strategic oil and gas acquisitions with exploitation upside, and at the same time, implement a full-cycle exploration program. Since the Company began active oil and gas operations in September 2002, Celtic has completed several corporate and property acquisitions in order to establish a cash flow platform and an inventory of exploration and development prospects from which the Company can grow through the drill bit.

In April 2004, Celtic completed the acquisition of an interest in the Morse River Beaverhill Lake oil unit for $3.4 million. Subsequent to this acquisition, the Company has acquired interests in undeveloped lands offsetting the Morse River Unit and has entered into farm-in agreements giving the Company access to additional undeveloped lands in the Morse River and Swan Hills areas. In 2005, this area was the most active for drilling operations. This is an example of Celtic's strategy to acquire an initial position in an area and subsequently expand the area, making it core to the Company. Other areas where Celtic has successfully employed this strategy include Fox Creek, Ashmont and Bantry.

During the year ended December 31, 2005, in addition to $5.2 million spent on property acquisitions, Celtic incurred $114.0 million on exploration and development activity. Drilling and completion operations accounted for $79.2 million and equipment and facility expenditures were $25.1 million. The balance was spent on land and seismic, building the Company's inventory of prospects for future drilling. Approximately 86% of net wells drilled were development and 14% were exploratory.

The Company's capital expenditure program, including acquisitions, is summarized in the following table:

Capital Expenditures

Years ended December 31	2005		2004		2003	
	$ thousands	% of total	$ thousands	% of total	$ thousands	% of total
Property, plant and equipment expenditures						
Lease acquisitions and retention	**6,676**	**6%**	2,492	5%	1,506	3%
Geological and geophysical activity	**2,941**	**2%**	2,666	5%	1,673	3%
Drilling and completion of wells	**79,202**	**67%**	35,941	64%	21,527	39%
Facilities, pipeline and well equipment	**25,075**	**21%**	13,151	24%	6,493	12%
Office furniture and equipment	**153**	**0%**	225	0%	175	0%
	114,047	**96%**	54,475	98%	31,374	57%
Property, plant and equipment acquisitions	**5,213**	**4%**	3,617	7%	23,808	43%
Property, plant and equipment dispositions	**(30)**	**–**	(2,947)	-5%	(108)	–
Corporate acquisitions	**–**	**–**	–	–	–	–
Capital expenditures	**119,230**	**100%**	55,145	100%	55,074	100%

UNDEVELOPED LAND
(net acres)

Undeveloped Land As at December 31, 2005, Celtic owned 164,239 net acres of undeveloped land, representing a 36% increase compared to 121,204 net acres at the end of 2004. Approximately 9% of the Company's undeveloped land position is subject to expiry in 2006, if not developed. Celtic holds an average working interest of 63% in its undeveloped lands.

In 2005, Celtic increased its undeveloped land base through Crown land sale acquisitions and farm-in arrangements. At Crown sales, Celtic acquired 31,481 net acres of new lands in Alberta, at an average cost of approximately $192 per acre, compared to the industry average of $256 per acre.

At December 31, 2005, Celtic had control over 95,680 gross (64,556 net) acres of undeveloped lands through various farm-in arrangements. The majority, 56,320 gross acres, is located in the Ashmont area of east central Alberta targeting Mannville gas; 15,360 gross acres are in the Swan Hills area of west central Alberta targeting Beaverhill Lake light oil and 16,000 gross acres in the Rainbow region of northern Alberta targeting Shunda gas.

Looking ahead to 2006, the high costs to acquire land experienced by the industry in 2005 are expected to continue in 2006. Celtic expects that its average price per acre paid for land will be higher in 2006 than in 2005, while the amount of acreage it acquires at Crown sales will decrease. This is a reflection of the Company's prospect-driven land acquisition strategy of acquiring high-value drill-ready prospects rather than acquiring larger blocks of potentially overvalued trend acreage. In addition, Celtic will continue to focus its land acquisition efforts on third-party farm-in arrangements providing the Company with a tax-effective basis for expanding its land holdings and minimizing the up-front land acquisition capital associated with its drilling programs.

The following table summarizes Celtic's land holdings as at December 31, 2005:

Undeveloped Land Holdings

As at December 31	2005		2004		2003	
(Acres)	Gross	Net	Gross	Net	Gross	Net
Alberta	**255,720**	**161,013**	198,918	117,983	150,695	74,692
British Columbia	**4,815**	**2,820**	4,815	2,820	4,815	2,820
Saskatchewan	**811**	**406**	802	401	802	401
Total owned undeveloped land	**261,346**	**164,239**	204,535	121,204	156,312	77,913
Option lands	**95,680**	**64,556**	147,000	119,000	–	–
Total controlled undeveloped land	**357,026**	**228,795**	351,535	240,204	156,312	77,913

Celtic's continued land acquisition strategy is prospect-driven with emphasis on internally generated opportunities that are in close proximity to facility infrastructure. The Company's long-term goal remains to build a large land base of high working interest undeveloped lands with Celtic operating the majority of its prospects, ensuring control of capital expenditures.

Drilling During the year ended December 31, 2005, Celtic drilled 100 (68.1 net) wells compared to 67 (41.5 net) wells in the previous year, with an overall success rate of 74% on net wells drilled. The split between development drilling and exploratory drilling was 86% and 14%, respectively. The average depth of net wells drilled was 1,967 metres, 34% deeper than the average drilling depth of 1,463 metres in 2004. The following table summarizes Celtic's drilling activity in 2005:

Drilling Activity

	Development wells		Exploration wells		Total wells	
Years ended December 31, 2005	Gross	Net	Gross	Net	Gross	Net
Oil	37	26.3	4	3.2	41	29.5
Natural gas	26	17.4	4	2.4	30	19.8
Coal bed methane	4	1.0	0	0.0	4	1.0
Unsuccessful	18	14.2	7	3.6	25	17.8
Total wells	85	58.9	15	9.2	100	68.1
Success rate, based on net wells		76%		61%		74%

Reserves Celtic retains Sproule Associates Limited ("Sproule"), an independent qualified reserve evaluator, to prepare a report on 100% of its oil and gas reserves. The Company has a Reserves Committee that oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves as at December 31, 2005 and 2004 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101"). At December 31, 2005, Celtic's proved plus probable reserves were 18.5 million BOE, up 68% from 11.1 million BOE at the end of 2004. The following table outlines the change in the Company's reserves year-over-year including discoveries, drilling extensions, improved recoveries, technical revisions, economic factors, acquisitions and production:

RESERVES
(mmBOE)

Reserves Reconciliation

	Oil		Natural gas		Combined	
	Total proved mbbls	Proved + probable mbbls	Total proved mmcf	Proved + probable mmcf	Total proved mBOE	Proved + probable mBOE
Balance, December 31, 2004	4,226	6,739	17,162	25,872	7,086	11,051
Revisions						
Technical revisions	(939)	(2,014)	(3,366)	(6,867)	(1,500)	(3,159)
Improved recoveries	881	1,289	3,993	5,703	1,547	2,240
Economic factors	342	520	570	768	437	648
Net revisions	284	(205)	1,197	(396)	484	(271)
Additions						
Discoveries	244	442	4,038	7,388	917	1,673
Extensions	1,646	3,221	8,887	15,717	3,127	5,841
Acquisitions	788	1,251	1,887	3,570	1,103	1,846
Net additions	2,678	4,914	14,812	26,675	5,147	9,360
Production	(921)	(921)	(4,159)	(4,159)	(1,614)	(1,614)
Balance, December 31, 2005	**6,267**	**10,527**	**29,012**	**47,992**	**11,103**	**18,526**
Percentage increase in reserves	48%	56%	69%	85%	57%	68%

The Company created value for its shareholders in 2005, significantly increasing the net present value of proved plus probable reserves, discounted at 10% before tax, to $389.0 million, up 137% from $164.4 million at December 31, 2004. In addition, the quality of reserves improved, resulting in a reserve life index of 10.0 years compared to 6.2 years at December 31, 2004. The following table outlines a summary of the Company's reserves at December 31, 2005:

Summary of Reserves

As at December 31, 2005	Oil mbbls	Gas mmcf	Combined mBOE	Q4 2005 Production BOE/d	Reserve Life Index years	NPV 10% BIT $ thousands	NPV per BOE $/BOE
Proved producing	5,960	18,410	9,028	5,094	4.9	231,916	25.69
Total proved	6,267	29,012	11,102	5,094	6.0	275,177	24.79
Total proved plus probable	10,527	47,992	18,526	5,094	10.0	389,030	21.00

Oil and gas selling prices have steadily increased over the past four years and current futures contracts indicate that prices will be higher in future years compared to historical averages. The following table outlines forecasted future prices that Sproule has used in their evaluation of the Company's reserves at December 31, 2005:

Reference Prices

			Oil			Natural Gas	
	Currency exchange rate US$/CA$	WTI Cushing Oklahoma US$/bbl	Edmonton light par CA$/bbl	Forecasted Celtic oil price [1] CA$/bbl	Henry Hub Louisiana US$/mmbtu	Alberta AECO-C Spot CA$/mmbtu	Forecasted Celtic gas price [2] CA$/mcf
Historical							
2001	0.646	25.94	39.06		4.27	6.23	
2002	0.637	26.09	40.12		3.22	4.04	
2003	0.716	31.14	43.23		5.39	6.66	
2004	0.826	41.42	52.91		6.14	6.87	
2005	0.850	56.45	69.28		8.62	8.58	
Five-year historical average	0.735	36.21	48.92		5.53	6.48	
Future Forecasts							
2006	0.850	60.81	70.07	66.70	11.59	11.58	12.49
2007	0.850	61.61	70.99	67.49	10.11	10.84	11.56
2008	0.850	54.60	62.73	59.11	8.50	8.95	9.56
2009	0.850	50.19	57.53	53.82	7.58	7.87	8.43
2010	0.850	47.76	54.65	50.88	7.32	7.57	8.12
Five-year forecast average	0.850	54.99	63.19	59.60	9.02	9.36	10.03

[1] Celtic's forecasted average oil price is based on total proved plus probable reserves and does not include NGLs.

[2] Celtic's forecasted average gas price is based on proved plus probable reserves.

During 2005, the Company's capital expenditures, net of dispositions, resulted in proved plus probable reserve additions (before net revisions) of 9.4 million BOE, resulting in finding, development and acquisition ("FD&A") costs of $14.22 per BOE. After revisions, FD&A costs were $14.64 per BOE. The recycle ratio is a measure for evaluating the effectiveness of a company's re-investment program. The ratio measures the efficiency of capital

NET ASSET VALUE
($/share)

investment. It accomplishes this by comparing the operating netback per BOE to that year's reserve FD&A cost per BOE. Since incorporation, Celtic has successfully achieved a recycle ratio of 2.5 times on a proved plus probable basis. The following table provides detailed calculations relating to FD&A costs and recycle ratios for 2005:

Finding, Development and Acquisition Costs

	Year ended December 31, 2005	Year ended December 31, 2004	Year ended December 31, 2003	April 16, to December 31, 2002	Cumulative since incorporation
Proved reserves					
Capital expenditures ($000s)	**119,230**	55,145	55,074	31,109	260,558
Change in future capital costs required to develop reserves ($000s)	**7,211**	3,662	323	845	12,041
Total capital costs ($000s)	**126,441**	58,807	55,397	31,954	272,599
Reserve additions, before net revisions (mBOE)	**5,147**	2,523	4,280	2,860	14,810
FD&A cost, before net revisions ($/BOE)	**24.57**	23.31	12.94	11.17	18.41
Reserve additions, including revisions (mBOE)	**5,631**	2,609	3,682	2,860	14,782
FD&A cost, including revisions ($/BOE)	**22.45**	22.54	15.05	11.17	18.44
Operating netback ($/BOE)	**37.20**	29.20	23.33	19.38	31.49
Recycle ratio – proved	**1.7**	1.3	1.6	1.7	1.7
Proved plus probable reserves					
Capital expenditures ($000s)	**119,230**	55,145	55,074	31,109	260,558
Change in future capital costs required to develop reserves ($000s)	**13,856**	6,535	(366)	1,883	21,908
Total capital costs ($000s)	**133,086**	61,680	54,708	32,992	282,466
Reserve additions, before net revisions (mBOE)	**9,360**	4,247	5,844	4,060	23,511
FD&A cost, before net revisions ($/BOE)	**14.22**	14.52	9.36	8.13	12.01
Reserve additions, including revisions (mBOE)	**9,089**	4,283	4,773	4,060	22,205
FD&A cost, including revisions ($/BOE)	**14.64**	14.40	11.46	8.13	12.72
Operating netback ($/BOE)	**37.20**	29.20	23.33	19.38	31.49
Recycle ratio – proved plus probable	**2.5**	2.0	2.0	2.4	2.5

Celtic's 2005 capital investment program replaced production by a factor of 3.5 times on a proved basis and 5.6 times on a proved plus probable basis. The following table summarizes production replacement for 2005:

Production Replacement

	Proved			Proved plus probable		
Year ended December 31, 2005	Oil mbbls	Gas mmcf	Combined mBOE	Oil mbbls	Gas mmcf	Combined mBOE
Reserve additions, including revisions	2,962	16,009	5,631	4,709	26,279	9,089
2005 production	921	4,159	1,614	921	4,159	1,614
Production replacement ratio	3.2	3.8	3.5	5.1	6.3	5.6

Net Asset Value Celtic's net asset value at December 31, 2005 increased to $360.2 million, up 134% from $154.0 million at December 31, 2004. On a per share basis, net asset value increased 108% to $11.53 per share. The present value of petroleum and natural gas ("P&NG") reserves was determined by Sproule in its year-end evaluation report. Undeveloped land at December 31, 2005 was valued at an average price of $120 per acre. The components of net asset value are summarized in the following table:

Net Asset Value

At December 31	2005	2004	2003
	Forecast prices $ thousands	Forecast prices $ thousands	Forecast prices $ thousands
Present value of P&NG reserves discounted at 10%, before tax	**389,030**	164,410	99,725
Undeveloped land	**19,709**	9,090	7,791
Bank debt, net of working capital	**(63,426)**	(29,663)	(10,785)
Proceeds from exercise of stock options	**14,849**	10,172	7,659
Net asset value	**360,162**	154,009	104,390
Diluted common shares outstanding (thousands)	**31,229**	27,763	27,432
Net asset value per share ($/share)	**11.53**	5.55	3.81

CAPITAL RESOURCES AND LIQUIDITY

Market Capitalization The Company's total capitalization increased 56% to $450.8 million at December 31, 2005. Market value of common shares represented 80% of total capitalization, while debt and working capital represented 14% of total capitalization. The following table summarizes the Company's capitalization:

G&A EXPENSE
($/BOE)

Capitalization

At December 31
($ thousands, except per share amounts)

	2005		2004		2003	
Common shares outstanding (000s)	28,973		25,835		25,790	
Share price (last price traded at in the year)	12.40		9.30		8.00	
Market capitalization	359,265	80%	240,266	84%	206,320	89%
Bank debt, net of working capital	63,426	14%	30,073	10%	10,785	5%
Asset retirement obligation	4,294	1%	3,307	1%	2,045	1%
Future income taxes	23,864	5%	15,680	5%	11,179	5%
Total capitalization	450,849	100%	289,326	100%	230,329	100%

At December 31, 2005, the Company had $41.7 million outstanding on its credit facility. Total debt, including working capital deficiency, was $63.4 million, representing approximately 1.1 times 2005 funds from operations and approximately 0.6 times forecasted 2006 funds from operations.

Key Debt Ratios

As at December 31	2005		2004		2003	
	$ thousands	Ratio	$ thousands	Ratio	$ thousands	Ratio
Bank debt	41,700		23,400		3,447	
Working capital deficiency	21,726		6,673		7,338	
Total debt	63,426		30,073		10,785	
Debt to funds from operations ratio:						
Total debt	63,426		30,073		10,785	
Funds from operations	56,969		36,381		15,314	
Funds from operations – 2006 forecast	107,700					
Debt to funds from operations – trailing		1.1		0.8		0.7
Debt to funds from operations – forward		0.6		0.5		0.3
Asset coverage ratio:						
Total assets	242,113		135,984		94,980	
Total debt	63,426		30,073		10,785	
Asset coverage		3.8		4.5		8.8
Debt to equity ratio:						
Total debt	63,426		30,073		10,785	
Shareholders' equity	125,847		76,436		64,118	
Debt/equity		0.5		0.4		0.2

Source of Funds Investment funding for capital expenditures incurred in 2005 was provided by proceeds from an equity financing, bank debt and cash provided by operating activities.

In May 2005, Celtic completed the issuance of 3.0 million common shares by way of private placement, at a price of $10.25 per share. The equity offering resulted in gross proceeds of $30.75 million.

The Company has in place a revolving demand loan facility with a Canadian chartered bank. The maximum amount available to be drawn under this facility at December 31, 2005 was $75.0 million. At December 31, 2005, Celtic had drawn $41.7 million, leaving significant unused credit lines available to fund working capital deficiency and future capital expenditures. Celtic expects to increase the maximum amount available under its credit facility after the Company's bankers complete their annual review in April 2006.

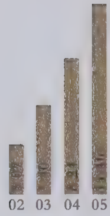
In order to fund all capital expenditures incurred in 2005, the Company augmented its equity financing and bank borrowings by generating $57.3 million in cash provided by operating activities for the year ended December 31, 2005.

Celtic expects to fund future capital expenditures through the use of a combination of cash provided by operating activities and bank debt, supplemented by new equity share offerings, as required.

Working Capital The capital intensive nature of Celtic's activities creates a working capital deficiency position during periods with high levels of capital investment. However, during such periods, the Company maintains sufficient unused bank credit lines to satisfy such working capital deficiencies. At December 31, 2005, the working capital deficiency amount plus outstanding bank debt represented 85% of the Company's maximum authorized bank borrowing credit limit.

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas. This occurs on the 25th day following the month of sale. As a result, the Company's production revenues are collected in an orderly fashion. Celtic monitors its revenue counterparty credit positions to mitigate any potential credit losses. To the extent that the Company has joint venture partners in its activities, it must collect the partners' share of capital expenditures and operating expenses on a monthly basis. Exceptions are in the event that the partners' share of a capital project is a significant amount. In this case, Celtic will collect such amounts from its partners in advance of expenditures taking place in accordance with standard industry operating procedures. At December 31, 2005, the Company did not have any material accounts receivable that were deemed uncollectible.

Accounts payable consist of amounts payable to suppliers relating to head office and field operating and investing activities. These invoices are processed within the Company's normal payment period.



AVERAGE TRADING SHARE PRICE *($/share)*

Celtic actively manages the pace of its capital spending program by monitoring forecasted production and commodity prices and resulting cash flows. Should circumstances affect cash flow in a detrimental way, the Company is capable of reducing capital investment levels.

Share Information The Company is authorized to issue an unlimited number of common shares and an unlimited number of preferred shares. As at December 31, 2005, there were 29.0 million common shares outstanding. There were no preferred shares outstanding. As at December 31, 2005, directors, employees and consultants have been granted options to purchase 2.2 million common shares of the Company at an average exercise price of $6.58 per share. Detailed information regarding the Company's stock options outstanding is contained in the notes to the financial statements. The following table outlines Celtic's common share trading activity by quarter during 2005, 2004 and 2003:

Share Trading Activity (CLT)

	Q1	Q2	Q3	Q4	2005
High ($)	**12.45**	**11.75**	**13.50**	**12.91**	**13.50**
Low ($)	**9.00**	**8.91**	**10.50**	**11.10**	**8.91**
Close ($)	**11.00**	**11.15**	**12.90**	**12.40**	**12.40**
Volume traded (thousands)	**4,172**	**3,986**	**4,627**	**3,677**	**16,462**
Value traded ($ thousands)	**45,333**	**42,390**	**56,662**	**44,290**	**188,675**
Weighted average trading price ($)	**10.87**	**10.63**	**12.25**	**12.05**	**11.46**

	Q1	Q2	Q3	Q4	2004
High ($)	8.15	8.50	8.98	9.95	9.95
Low ($)	6.70	7.11	7.60	8.40	6.70
Close ($)	7.45	7.75	8.80	9.30	9.30
Volume traded (thousands)	2,511	2,660	2,075	2,823	10,069
Value traded ($ thousands)	19,278	21,328	16,594	25,785	82,985
Weighted average trading price ($)	7.68	8.02	8.00	9.13	8.24

	Q1	Q2	Q3	Q4	2003
High ($)	4.60	5.95	6.70	8.00	8.00
Low ($)	3.90	3.95	5.10	5.55	3.90
Close ($)	4.06	5.20	6.00	8.00	8.00
Volume traded (thousands)	1,264	1,680	1,259	3,106	7,309
Value traded ($ thousands)	5,246	7,816	7,475	18,901	39,438
Weighted average trading price ($)	4.15	4.65	5.94	6.09	5.40

Contractual Obligations Celtic has a demand revolving credit facility with a Canadian chartered bank. The authorized borrowing amount under this facility as at December 31, 2005 was $75.0 million, of which $41.7 million was outstanding. Interest under this facility is payable monthly. Additional disclosure relating to bank debt is provided in the notes to the financial statements.

From time to time, the Company enters into agreements to transport and market oil and gas production. In addition, the Company has entered into agreements with third parties that provide employees with access to specialized computer software and information including production and reserves data, geological data, accounting systems and land management systems.

As a normal course of business, the Company leases office space, vehicles for field personnel and office equipment such as computers, printers and photocopiers.

Related-party Transactions The Company has retained the law firm of Borden Ladner Gervais LLP to provide Celtic with legal services. William C. Guinan, a director, chairman and corporate secretary of Celtic, is a partner of this law firm. The Company expects to continue using the services of this law firm from time to time.

SUPPLEMENTAL QUARTERLY INFORMATION

The Company has been successful in providing strong growth in funds from operations and daily average production. The following tables summarize key financial and operating information by quarter:

FUNDS FROM OPERATIONS
($/share)

Quarterly Financial Information

($ thousands, except per share amounts)

2005	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	14,099	13,645	22,186	26,647	76,577
Funds from operations	10,489	10,724	17,082	18,674	56,969
Funds from operations per share – basic	0.41	0.39	0.59	0.65	2.05
Funds from operations per share – diluted	0.39	0.38	0.57	0.62	1.98
Net earnings	3,018	2,455	5,729	7,062	18,264
Earnings per share – basic	0.12	0.09	0.20	0.24	0.66
Earnings per share – diluted	0.11	0.09	0.19	0.24	0.64
Total assets	155,257	178,574	207,074	242,113	242,113
Bank debt, net of working capital	43,277	29,589	42,003	63,426	63,426

2004	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	11,212	11,976	13,986	13,086	50,260
Funds from operations	8,195	8,472	10,155	9,559	36,381
Funds from operations per share – basic	0.32	0.33	0.39	0.37	1.41
Funds from operations per share – diluted	0.31	0.32	0.38	0.36	1.37
Net earnings	2,047	2,582	3,594	3,278	11,501
Earnings per share – basic	0.08	0.10	0.14	0.13	0.45
Earnings per share – diluted	0.08	0.10	0.14	0.12	0.43
Total assets	106,166	114,246	122,416	135,984	135,984
Bank debt, net of working capital	15,576	19,225	20,572	30,073	30,073

2003	Q1	Q2	Q3	Q4	Total
Revenue, net of royalties	4,617	4,582	5,924	7,307	22,430
Funds from operations	3,432	3,087	4,008	4,787	15,314
Funds from operations per share – basic	0.19	0.14	0.17	0.19	0.69
Funds from operations per share – diluted	0.18	0.14	0.17	0.18	0.68
Net earnings	1,138	809	1,789	961	4,697
Earnings per share – basic	0.06	0.04	0.08	0.04	0.21
Earnings per share – diluted	0.06	0.04	0.07	0.04	0.21
Total assets	53,159	75,986	84,703	94,980	94,980
Bank debt, net of working capital	5,748	11,299	3,878	10,785	10,785

Quarterly Operating Information

2005	Q1	Q2	Q3	Q4	Total
Production					
Oil (bbls/d)	2,269	2,067	2,833	2,915	2,524
Natural gas (mcf/d)	8,856	10,101	13,485	13,071	11,396
Combined (BOE/d)	3,745	3,751	5,081	5,094	4,423
Production per million shares (BOE/d)	145	136	176	176	159
Realized sales prices					
Oil ($/bbl)	53.91	60.38	70.57	61.03	62.02
Natural gas ($/mcf)	8.33	7.54	9.14	12.48	9.60
Combined ($/BOE)	52.35	53.57	63.60	66.95	60.11
Operating netbacks					
Oil ($/bbl)	35.80	34.99	40.32	35.37	36.79
Natural gas ($/mcf)	5.05	5.26	5.83	8.38	6.29
Combined ($/BOE)	33.64	33.42	37.95	41.76	37.20

2004	Q1	Q2	Q3	Q4	Total
Production					
Oil (bbls/d)	2,281	2,314	2,396	2,142	2,283
Natural gas (mcf/d)	8,054	7,372	8,086	8,292	7,952
Combined (BOE/d)	3,623	3,543	3,744	3,524	3,608
Production per million shares (BOE/d)	140	137	145	136	140
Realized sales prices					
Oil ($/bbl)	42.89	45.79	53.06	53.08	48.71
Natural gas ($/mcf)	6.57	7.29	6.91	7.13	6.97
Combined ($/BOE)	41.59	45.07	48.86	49.04	46.15
Operating netbacks					
Oil ($/bbl)	28.19	30.08	34.58	34.66	31.88
Natural gas ($/mcf)	3.77	4.00	4.12	4.48	4.11
Combined ($/BOE)	26.13	27.98	31.02	31.62	29.20

EARNINGS
($/share)

2003	Q1	Q2	Q3	Q4	Total
Production					
Oil (bbls/d)	605	829	1,270	1,505	1,055
Natural gas (mcf/d)	4,423	4,332	5,161	7,324	5,318
Combined (BOE/d)	1,342	1,551	2,130	2,726	1,941
Production per million shares (BOE/d)	72	72	89	105	87
Realized sales prices					
Oil ($/bbl)	42.50	33.46	35.17	34.87	35.76
Natural gas ($/mcf)	8.45	7.02	5.99	5.73	6.61
Combined ($/BOE)	47.00	37.49	35.48	34.64	37.55
Operating netbacks					
Oil ($/bbl)	26.73	21.06	22.48	20.85	22.22
Natural gas ($/mcf)	5.41	4.48	3.78	3.36	4.10
Combined ($/BOE)	29.86	23.77	22.56	20.54	23.33

Factors that have caused variations over the quarters:

- Oil and gas property acquisitions completed in 2003, 2004 and 2005 contributed to production growth:
  - the $18.5 million acquisition of oil and gas properties complementing Celtic's existing core producing areas completed in June 2003 added approximately 740 BOE per day of production, consisting of 517 bbls per day of oil and 1.34 mmcf per day of natural gas;
  - the acquisition of an oil and gas property at Fox Creek for $4.4 million completed in September 2003 added approximately 200 BOE per day of production, consisting of 140 bbls per day of oil and 360 mcf per day of natural gas;
  - the $3.4 million acquisition of a property at Morse River completed in April 2004 added approximately 120 bbls per day of oil production; and

- in 2005, Celtic completed the acquisition of complementary oil and gas properties in the Swan Hills/Virginia Hills area of west central Alberta for approximately $2.5 million, adding approximately 350 BOE/d (73% oil and 27% natural gas).

- The majority of the Company's production growth has been the result of the Company's successful exploration and development drilling activities.
- Revenue, funds from operations and earnings growth is primarily the result of production growth and increases in commodity prices.

BUSINESS RISKS

Celtic's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers, intermediate and senior producers and royalty trust organizations, to the much larger integrated petroleum companies. Celtic is subject to a number of risks that are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Celtic employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Celtic explores in areas that afford multi-zone prospect potential, targeting a range of shallower low-to-moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Celtic has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Celtic strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Celtic does not operate.

Celtic is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Celtic may periodically use futures and options contracts to hedge its exposure to the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas are very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Celtic utilizes bank financing to support ongoing capital investment. Funds from operations also provide Celtic with capital required to grow its business. Equity and debt capital are subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Celtic maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.

BUSINESS OUTLOOK

Advisory Regarding Forward-looking Statements Certain information with respect to Celtic contained herein, including management's assessment of future plans and operations, contains forward-looking statements. These forward-looking statements are based on assumptions and are subject to numerous risks and uncertainties, certain of which are beyond Celtic's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency exchange rate fluctuations, imprecision of reserve estimates, environmental risks, competition from other explorers, stock market volatility and ability to access sufficient capital. As a result, Celtic's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur. In addition, the reader is cautioned that historical results are not necessarily indicative of future performance.

2006 Forecast Celtic is optimistic about its future prospects. The Company was successful in establishing a production base during the early months since commencing operations that provides a cash flow stream that can be re-invested in Celtic's ongoing exploration and development activity. Celtic is opportunity driven and is confident that it can continue to grow the Company's production base by building on its current inventory of development prospects and by adding new exploration prospects. Celtic will endeavour to maintain a high-quality product stream that on an historical basis receives a superior price with reasonably low production costs. In addition, the Company takes advantage of royalty incentive programs in order to further increase netbacks. Celtic will continue to focus its exploration efforts in areas of multi-zone potential for light gravity crude oil and liquids-rich natural gas.

Celtic's Board of Directors has approved an initial capital expenditure budget in the amount of $120 million for 2006. This capital spending will be financed by funds from operations and bank credit lines.

After forecasting risked production discoveries, timing of production on-stream dates resulting from the Company's planned capital expenditures for 2005 and estimated decline rates on existing volumes, Celtic expects production in 2006 to average between 7,200 and 7,600 BOE/d (55% oil and 45% gas). This represents a 63% to 72% increase from average production of 4,423 BOE/d in 2005.

World oil demand continued to show resilient growth in 2005. The response in world oil supply has left major oil exporting nations with limited spare productive capacity. In addition, political turmoil in major oil-producing regions around the world has put further strains on stable world oil supply. As a result, Celtic expects oil prices to remain strong in 2006. Natural gas demand in North America also expanded in 2005, resulting in record natural gas drilling

in Canada and the United States. However, a warmer than normal winter has left sufficient natural gas in storage and may put pressure on natural gas prices in the short term. Longer term natural gas prices will benefit from increases in demand until supply increases significantly with the introduction of additional volumes of liquefied natural gas ("LNG") expected in three to four years. The Company's commodity price assumptions for 2006 are US$61.00 per barrel for WTI oil, US$8.50 per mmbtu for natural gas and a U.S./Canadian exchange rate of US$0.862.

After giving effect to the aforementioned production and commodity price assumptions and taking into effect commodity risk price management contracts in place (as outlined in detail in the notes to the financial statements), funds from operations for 2006 are forecasted to be approximately $107.7 million or $3.72 per share ($3.52 per share, diluted) and net earnings are forecasted to be approximately $40.0 million or $1.38 per share ($1.31 per share, diluted). Changes in forecasted commodity prices can have a significant effect on estimated funds from operations and net earnings. As a result, the following table is provided to show the sensitivities of changes in commodity prices to the estimated funds from operations and net earnings for 2006:

2006 Sensitivities

	Funds from operations	Funds from operations per share
	$ thousands	$
US$1.00 per bbl increase in WTI oil price	890	0.031
$0.20 per mcf increase in Celtic realized gas price	420	0.014
US$0.01 decrease in USD/CAD exchange rate	1,260	0.043
1% decrease in bank borrowing rate	610	0.021

	Net earnings	Earnings per share
	$ thousands	$
US$1.00 per bbl increase in WTI oil price	590	0.020
$0.20 per mcf increase in Celtic realized gas price	270	0.009
US$0.01 decrease in USD/CAD exchange rate	830	0.029
1% decrease in bank borrowing rate	400	0.014

Bank debt, net of working capital, is estimated to reach $75.7 million by the end of 2006 or approximately 0.7 times forecasted 2006 funds from operations.

Celtic's capital expenditure budget for 2006 will see the Company participate at high working interests in the drilling of approximately 100 wells during the year. Celtic continues to pursue property acquisitions that would complement its existing asset base and completion of such acquisitions would be over and above the Company's planned capital expenditure budget.

Celtic is excited about the growth prospects being generated in the Company and remains optimistic about the Company's ability to deliver continued per share growth in production, funds from operations and earnings. Given the Company's strong inventory of drilling locations, we look forward to continued growth in 2006.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), on a timely basis so appropriate decisions can be made regarding public disclosure. As at December 31, 2005, the CEO and the CFO have evaluated the effectiveness of Celtic's disclosure controls and procedures as defined in Multilateral Instrument 52-109 of the Canadian Securities Administrators and have concluded that such disclosure controls and procedures are effective.

ADDITIONAL INFORMATION

Additional information relating to Celtic, including the Company's Annual Information Form ("AIF") is filed on SEDAR and can be viewed on their website at www.sedar.com. Copies of the AIF can also be obtained by contacting Sadiq H. Lalani, Vice President, Finance and Chief Financial Officer at Celtic Exploration Ltd., Suite 500, 505 Third Street S.W., Calgary, Alberta, Canada, T2P 3E6. Further information relating to the Company is also available on its website at www.celticex.com.

MANAGEMENT'S REPORT

Management has prepared the accompanying financial statements of Celtic Exploration Ltd. in accordance with Canadian generally accepted accounting principles. Financial information presented throughout this annual report is consistent with that shown in the financial statements.

Management is responsible for the integrity of the financial information. Where appropriate, management has made informed judgments and estimates in accounting for transactions which affect the current accounting period but cannot be finalized with certainty until future periods. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

PricewaterhouseCoopers LLP was appointed by the Company's shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the financial statements. Their examination included a review and evaluation of Celtic's internal control systems and included such tests and procedures, as they considered necessary, to provide reasonable assurance that the financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility with the assistance of the Audit Committee. This Committee, consisting of non-management directors, meets with management and independent auditors to ensure that each group is properly discharging its responsibilities and to discuss adequacy of internal controls, accounting policies and financial reporting matters. The Audit Committee has reviewed the financial statements and has reported thereon to the Board of Directors. The Board has approved the financial statements for issuance to the shareholders.

David J. Wilson
President and Chief Executive Officer

Sadiq H. Lalani
Vice President, Finance and Chief Financial Officer

February 27, 2006

AUDITORS' REPORT

To the Shareholders of Celtic Exploration Ltd.

We have audited the balance sheets of Celtic Exploration Ltd. as at December 31, 2005 and 2004, and the statements of operations and retained earnings and cash flows for the years ended December 31, 2005 and 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and 2004, and the results of its operations and its cash flows for the years ended December 31, 2005 and 2004, in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

February 27, 2006

BALANCE SHEET

As at December 31, ($ thousands)	2005	2004
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,812	$ 62
Accounts receivable	22,582	10,132
Prepaid expenses	288	294
	24,682	10,488
Other assets	1,160	410
Property, plant and equipment *(Note 2)*	216,271	125,086
	$ 242,113	$ 135,984
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 46,408	$ 17,161
Bank debt *(Note 3)*	41,700	23,400
	88,108	40,561
Asset retirement obligation *(Note 4)*	4,294	3,307
Future income taxes *(Note 6b)*	23,864	15,680
	$ 116,266	$ 59,548
SHAREHOLDERS' EQUITY		
Share capital *(Note 5)*	$ 89,812	$ 59,446
Contributed surplus	1,545	764
Retained earnings	34,490	16,226
	$ 125,847	$ 76,436
	$ 242,113	$ 135,984

The accompanying notes form an integral part of these financial statements.

ON BEHALF OF THE BOARD OF DIRECTORS:

Director

Director

STATEMENT OF OPERATIONS AND RETAINED EARNINGS

Twelve months ended December 31, *($ thousands, except per share amounts)*	2005	2004
REVENUE		
Oil and natural gas	$ 97,207	$ 61,056
Royalties, net	(17,731)	(10,796)
Realized loss on financial derivatives	(2,899)	–
	$ 76,577	$ 50,260
EXPENSES		
Production	$ 15,352	$ 10,727
Transportation and selling	1,168	954
Interest	1,079	540
General and administrative	1,909	1,550
Stock-based compensation *(Note 5)*	844	605
Depletion, depreciation and amortization	28,863	19,557
Accretion of asset retirement obligation *(Note 4)*	213	195
	$ 49,428	$ 34,128
Earnings before taxes	$ 27,149	$ 16,132
Capital tax	100	108
Future income taxes *(Note 6a)*	8,785	4,523
Net earnings	$ 18,264	$ 11,501
Retained earnings, beginning of period	16,226	4,725
Retained earnings, end of period	$ 34,490	$ 16,226
Earnings per share		
Basic	$ 0.66	$ 0.45
Diluted *(Note 7)*	$ 0.64	$ 0.43

The accompanying notes form an integral part of these financial statements.

STATEMENT OF CASH FLOWS

Twelve months ended December 31, *($ thousands)*	2005	2004
OPERATING ACTIVITIES		
Net earnings	$ 18,264	$ 11,501
Items not affecting cash:		
Depletion, depreciation and amortization	28,863	19,557
Accretion of asset retirement obligation	213	195
Stock-based compensation	844	605
Future income taxes	8,785	4,523
Funds from operations	$ 56,969	$ 36,381
Asset retirement expenditures	(44)	(325)
Change in non-cash operating working capital *(Note 10)*	398	(5,703)
Cash provided by operating activities	$ 57,323	$ 30,353
FINANCING ACTIVITIES		
Increase in bank debt	$ 18,300	$ 19,953
Issue of common shares, net of costs	29,702	212
Cash provided by financing activities	$ 48,002	$ 20,165
INVESTING ACTIVITIES		
Property and equipment expenditures	$(114,047)	$ (54,475)
Property and equipment acquisitions	(5,213)	(3,617)
Property and equipment dispositions	30	2,947
Change in other assets	(750)	(206)
Change in non-cash investing working capital *(Note 10)*	16,405	4,858
Cash used in investing activities	$(103,575)	$ (50,493)
Net change in cash and cash equivalents	$ 1,750	$ 25
Cash and cash equivalents, beginning of period	62	37
Cash and cash equivalents, end of period	$ 1,812	$ 62

The accompanying notes form an integral part of these financial statements.

NOTE 1 SIGNIFICANT ACCOUNTING POLICIES

Nature of business and basis of presentation Celtic Exploration Ltd. ("Celtic" or the "Company") was incorporated under the *Business Corporations Act* (Alberta) on April 16, 2002 as Desco Exploration Ltd. The Company changed its name to Celtic Exploration Ltd. on September 30, 2002. Celtic is an oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in Western Canada, primarily in Alberta.

These financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates.

Measurement uncertainty The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment and the provision for asset retirement obligation costs are based on estimates. In addition, the ceiling test calculation is based on estimates of proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Joint interests A portion of the Company's exploration, development and production activities is conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

Cash and cash equivalents Cash and cash equivalents include cash on hand, demand deposits and investments in highly liquid money market instruments which are convertible to known amounts of cash in less than three months.

Financial instruments The fair market values of cash and cash equivalents, receivables, other current assets, payables and bank debt approximate their carrying value. From time to time, the Company may use derivative financial instruments to manage exposure to fluctuations in commodity prices and foreign currency exchange rates. All transactions of this nature entered into by the Company are related to an underlying financial position or to future petroleum and natural gas production. The Company does not use derivative financial instruments for speculative trading purposes.

Property, plant and equipment The Company follows the full-cost method of accounting whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition, geological and geophysical, drilling of productive and non-productive wells, production equipment and facilities, carrying costs directly related to unproved properties and costs related to acquisition of petroleum and natural gas assets directly or by means of a business combination. These capitalized costs, along with estimated future

capital expenditures to be incurred in order to develop proved reserves, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves as evaluated by independent engineers. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs.

Gains or losses on the disposition of properties are not recognized unless the proceeds on disposition result in a change of 20 percent or more in the depletion rate.

Depreciation of furniture and office equipment is provided using the declining balance method at a rate of 25 percent.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from undiscounted future net cash flows based on proved reserves, which are determined by using forecasted future prices, plus unproved properties. If the carrying amount exceeds the ultimate recoverable amount, an impairment loss is recognized in net earnings. The impairment loss is limited to the amount by which the carrying amount exceeds: (i) the sum of the fair value of proved and probable reserves; and (ii) the costs of unproved properties that have been subject to a separate impairment test and contain no probable reserves.

Asset retirement obligations Estimated future costs relating to retirement obligations associated with oil and gas well sites and facilities are recognized as a liability, at fair value. The asset retirement cost, equal to the fair value of the retirement obligation, is capitalized as part of the cost of the related asset. These capitalized costs are amortized on a unit-of-production basis, consistent with depletion and depreciation. The liability is adjusted at each reporting period to reflect the passage of time, with the accretion charged to earnings. Actual costs incurred upon settlement of the obligations are charged against the liability.

Future income taxes The Company follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Flow-through shares Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share issues are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as a future income tax liability, at the time the renunciation documents are filed with the tax authorities, and a reduction in share capital.

Revenue recognition Revenue from the sale of oil and natural gas is recorded when title passes to an external party.

Stock-based compensation The Company has a stock-based compensation plan and uses the fair-value method to record compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant and a provision for the costs is provided for as contributed surplus over the term of the option agreement. The consideration received by the Company on the exercise of share options is recorded as an increase to share capital together with corresponding amounts previously recognized in contributed surplus. Forfeitures are accounted for as they occur which could result in recoveries of the compensation expense.

Per share amounts Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Weighted average number of shares is determined by relating the portion of time within the reporting period that common shares have been outstanding to the total time in that period.

Diluted per share amounts are calculated using the treasury stock method which assumes that any proceeds obtained on exercise of share options or other dilutive instruments would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

NOTE 2 PROPERTY, PLANT AND EQUIPMENT

At December 31, 2005	Cost	Accumulated depletion, depreciation and amortization	Net book value
Oil and gas properties, plant and equipment	$ 270,555	$ 57,388	$ 213,167
Asset retirement obligation costs	4,168	1,471	2,697
Head office assets	632	225	407
	$ 275,355	$ 59,084	$ 216,271

At December 31, 2004	Cost	Accumulated depletion, depreciation and amortization	Net book value
Oil and gas properties, plant and equipment	$ 151,479	$ 29,059	$ 122,420
Asset retirement obligation costs	3,349	1,037	2,312
Head office assets	479	125	354
	$ 155,307	$ 30,221	$ 125,086

At December 31, 2005, oil and gas properties with a cost of $16.7 million (December 31, 2004 – $8.5 million) relating to undeveloped properties have been excluded from the depletion and depreciation calculation. Future capital costs required to develop proved reserves in the amount of $12.0 million (2004 – $4.8 million) are included in the depletion and depreciation calculation.

Celtic does not capitalize any interest or general and administrative expenses that are not directly related to exploration and development activities. In 2005, the Company capitalized $0.5 million (2004 – $0.4 million) with respect to employee salaries directly relating to exploration and development activities.

As a result of the ceiling test calculation at December 31, 2005, the Company was not required to record an impairment loss. The forecasted future prices used for the next 10 years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2005 were as follows:

	2006	2007	2008	2009	2010
Oil ($/bbl)	$ 66.25	$ 66.57	$ 58.34	$ 53.34	$ 50.38
NGLs ($/bbl)	50.93	50.50	44.56	40.77	38.66
Natural gas ($/mcf)	12.49	11.55	9.56	8.44	8.14

	2011	2012	2013	2014	2015
Oil ($/bbl)	$ 50.98	51.65	52.34	53.08	54.12
NGLs ($/bbl)	39.31	39.89	40.37	41.14	41.78
Natural gas ($/mcf)	8.28	8.43	8.58	8.73	8.90

Prices escalate at approximately 1.5% thereafter.

For comparative purposes, the forecasted future prices used for the next 10 years in the ceiling test evaluation of the Company's proved reserves as at December 31, 2004 were as follows:

	2005	2006	2007	2008	2009
Light/medium oil ($/bbl)	$ 48.82	$ 45.60	$ 40.06	$ 35.74	$ 33.89
Heavy oil ($/bbl)	38.25	36.70	33.78	32.22	30.50
Natural gas ($/mcf)	7.37	6.84	6.41	5.97	5.65

	2010	2011	2012	2013	2014
Light/medium oil ($/bbl)	$ 34.47	$ 35.07	$ 35.61	$ 37.30	$ 37.95
Heavy oil ($/bbl)	30.90	31.17	31.13	31.22	31.76
Natural gas ($/mcf)	5.77	5.89	6.01	6.13	6.27

Prices escalate at approximately 1.5% thereafter.

NOTE 3 BANK DEBT

At December 31	2005	2004
Demand operating loan	$ 21,700	$ 13,400
Bankers' acceptances	20,000	10,000
	$ 41,700	$ 23,400

Celtic has a demand revolving credit facility with a Canadian chartered bank. The authorized borrowing amount under this facility is $75.0 million. Interest is payable monthly for borrowings through direct advances. Interest rates fluctuate based on a pricing grid and range from bank prime to bank prime plus 1.5%, depending upon the Company's then current debt to cash flow ratio of between less than one and a half times to greater than three times. At December 31, 2005, interest was payable at bank prime. Under the credit facility, borrowings through the use of bankers' acceptances are also available. The Company has a fixed rate bankers' acceptance in the amount of $20.0 million maturing on January 16, 2006 at an aggregate interest rate of 4.1%. Security is provided for by a floating charge debenture over all assets in the amount of $150.0 million, general assignment of book debts and a fixed charge on the Company's major producing petroleum and natural gas properties.

Repayments of principal are not required provided that the borrowings under the facility do not exceed the authorized borrowing amount and the Company is in compliance with all covenants, representations and warranties. The credit facility revolves until April 30, 2006, at which time the bank will complete its annual review.

NOTE 4 ASSET RETIREMENT OBLIGATION

The following table provides a reconciliation of the carrying amount of the obligation associated with the retirement of oil and gas properties:

At December 31	2005	2004
Asset retirement obligation, beginning of year	$ 3,307	$ 2,045
Liabilities incurred, net of liabilities disposed	797	1,218
Liabilities settled	(44)	(325)
Revisions to estimated liabilities	21	174
Accretion expense	213	195
Asset retirement obligation, end of year	$ 4,294	$ 3,307

The key assumptions, on which the carrying amount of the asset retirement obligations is based, include a credit-adjusted risk-free rate of 8.5% and an inflation rate of 2.2%. The total undiscounted amount of the estimated cash flows required to settle the obligations was $12.4 million (December 31, 2004 – $7.7 million). The expected timing of payment of the cash flows required to settle the obligations ranges from 6.0 years to 51.4 years.

NOTE 5 SHARE CAPITAL

Authorized Unlimited number of common shares.
Unlimited number of preferred shares.

Issued The following table summarizes the changes in common shares outstanding during the years ended December 31, 2004 and December 31, 2005:

	Common shares	Amount
Balance, December 31, 2003	25,790	$ 59,211
Issued for cash on exercise of stock options	45	214
Amount relating to exercised options previously recorded as contributed surplus	–	23
Share issue costs, after future income taxes	–	(2)
Balance, December 31, 2004	25,835	$ 59,446
Issued for cash on exercise of stock options	138	550
Amount relating to exercised options previously recorded as contributed surplus	–	63
Issued for cash through private placement	3,000	30,750
Share issue costs, after future income taxes	–	(997)
Balance, December 31, 2005	**28,973**	**$ 89,812**

a) Stock options Celtic has a stock option plan that provides for granting of stock options to directors, officers, employees and consultants. Stock options granted under the stock option plan have a maximum term of five years to expiry. Vesting is determined by the Company's Board of Directors. However, the majority of the options granted vest equally over a three-year period commencing on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day of grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

The following table summarizes the changes in stock options outstanding during the years ended December 31, 2004 and December 31, 2005:

	Number of options	Average exercise price
Balance, December 31, 2003	1,642	$ 4.66
Granted	436	7.76
Exercised	(45)	4.75
Forfeited	(105)	6.22
Balance, December 31 2004	1,928	$ 5.28
Granted	466	11.22
Exercised	(138)	3.99
Balance, December 31, 2005	**2,256**	**$ 6.58**

The Company uses the fair-value method to record stock-based compensation expense with respect to stock options granted. The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2005	2004
Risk-free interest rate	3.37%	3.19%
Expected life (years)	3.0	3.0
Expected volatility	32%	34%
Expected dividend yield	0%	0%
Fair value of options granted during the year ($/share)	2.31	1.85

The following table summarizes information regarding stock options outstanding at December 31, 2005:

Range of exercise prices per share	Number of options outstanding	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable	Weighted average exercise price per share for options exercisable
$ 2.01 to $ 3.50	497	1.8	$ 3.02	497	$ 3.02
$ 3.51 to $ 5.00	125	2.1	$ 4.06	77	4.07
$ 5.01 to $ 6.50	748	2.8	$ 5.80	207	5.70
$ 6.51 to $ 8.00	390	3.7	$ 7.71	123	7.74
$ 8.01 to $ 9.50	30	3.8	$ 8.65	10	8.65
$ 9.51 to $11.00	185	4.2	$ 10.69	–	–
$11.01 to $12.50	281	4.8	$ 11.57	–	–
Total	2,256	3.1	$ 6.58	914	$ 4.42

For comparative purposes, the following table summarizes information regarding stock options outstanding at December 31, 2004:

Range of exercise prices per share	Number of options outstanding	Weighted average remaining term in years	Weighted average exercise price per share for options outstanding	Number of options exercisable	Weighted average exercise price per share for options exercisable
$ 2.01 to $ 3.50	578	2.8	$ 3.02	297	$ 3.02
$ 3.51 to $ 5.00	140	3.1	$ 4.06	43	4.06
$ 5.01 to $ 6.50	779	3.8	$ 5.79	104	5.71
$ 6.51 to $ 8.00	401	4.6	$ 7.70	–	–
$ 8.01 to $ 9.50	30	4.8	$ 8.65	–	–
Total	1,928	3.6	$ 5.28	444	$ 3.75

NOTE 6 INCOME TAXES

a) Future income tax expense The provision for income taxes differs from the expected amount calculated by applying the combined federal and provincial corporate income tax rate as a result of the following:

	2005	2004
Earnings before taxes	$ 27,149	$ 16,132
Statutory combined federal and provincial income tax rate	37.62%	38.87%
Expected income taxes	10,213	6,271
Increase (decrease) resulting from:		
Non-deductible Crown payments	2,890	2,174
Non-deductible stock-based compensation costs	286	–
Non-taxable provincial royalty credits (ARTC)	(110)	(168)
Allowable resource allowance deduction	(3,677)	(2,990)
Benefit relating to changes in future income tax rates	(833)	(775)
Other adjustments	16	11
Provision for future income taxes	**$ 8,785**	**$ 4,523**

b) Future income tax liability The components of future income taxes are as follows:

At December 31	2005	2004
Future income tax liabilities:		
Property, plant and equipment	$ 26,072	$ 17,294
Future income tax assets:		
Asset retirement obligation costs	(1,455)	(1,127)
Share issue costs	(708)	(442)
Other income tax assets	(45)	(45)
Future income taxes	**$ 23,864**	**$ 15,680**

NOTE 7 EARNINGS PER SHARE

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under this method, only "in-the-money" dilutive instruments impact the calculations in computing diluted earnings per share.

In computing diluted earnings per share, 0.8 million (2004 – 0.7 million) shares were added to the 27.8 million (2004 – 25.8 million) weighted average number of common shares outstanding during the year for the dilutive effect of stock options.

NOTE 8 COMMITMENTS

The Company is committed to payments under a rental agreement for office space as follows:

		Amount
2006	$	272
2007		506
2008		506
2009		506
2010		506
2011		169
	$	2,465

Rental leases relating to office space expire on April 30, 2011.

NOTE 9 FINANCIAL INSTRUMENTS

a) Fair values of financial assets and liabilities Financial instruments of the Company consist mainly of cash and cash equivalents, receivables, payables and bank debt. At December 31, 2005 and 2004, there were no significant differences between the carrying amounts reported on the balance sheets and their estimated fair values.

b) Credit risk The majority of the Company's accounts receivable is in respect of oil and gas operations. Celtic generally extends unsecured credit to these third parties, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Celtic has not experienced any material credit loss in the collection of receivables in 2005 and 2004.

c) Interest rate risk The Company is exposed to fluctuations in interest rates on its bank debt. Interest rate risk is mitigated through short-term fixed-rate borrowings using bankers' acceptances.

d) Foreign exchange rate risk The Company is exposed to the risk of changes in the Canadian/U.S. dollar exchange rate on sales of commodities that are denominated in U.S. dollars or directly influenced by U.S. dollar benchmark prices.

e) Commodity risk management From time to time, the Company may use financial derivative instruments to manage its exposure to fluctuations in commodity prices and foreign currency exchange rates. Under the terms of certain financial derivative contracts, Celtic may be required to provide security from time to time depending on the underlying market value of those contracts.

The Company accounts for financial derivative instruments using the Canadian accounting standard outlined in the *CICA Handbook Accounting Guideline 13*, "Hedging Relationships." This guideline addresses the identification, designation and effectiveness of financial contracts for the purpose of applying hedge accounting. Under this

guideline, financial derivative contracts must be designated to the underlying revenue or expense stream that they are intended to hedge, and tested to ensure they remain sufficiently effective. For transactions that do not qualify as designated hedges, the Company applies a fair-value method of accounting by initially recording an asset or liability, and recognizing changes in the fair value of the derivative instrument in income.

The following is a summary of oil sales price derivative contracts in effect as at December 31, 2005 that have fixed future sales prices (fixed oil prices are based on the West Texas Intermediate [WTI] Index):

Daily quantity	Remaining term of contract	Fixed price per bbl
750 bbls/d	January 1 to December 31, 2006	US$61.20
300 bbls/d (costless collar)	January 1 to December 31, 2006	US$60.00 (floor) US$65.20 (cap)
750 bbls/d (costless collar)	January 1 to December 31, 2006	US$60.00 (floor) US$70.10 (cap)

The fair value of the above oil contracts, mark-to-market at December 31, 2005, is an unrealized loss of $1.2 million.

The following is a summary of natural gas sales price derivative contracts in effect as at December 31, 2005 that have fixed future sales prices (fixed natural gas prices are based on the New York Mercantile Exchange [NYMEX] Index):

Daily quantity	Remaining term of contract	Fixed price per mmbtu
4,000 mmbtu/d	January 1 to March 31, 2006	US$11.94
4,000 mmbtu/d	April 1 to October 31, 2006	US$10.01

The fair value of the above natural gas contracts, mark-to-market at December 31, 2005, is an unrealized gain of $1.2 million.

In addition to financial derivative instruments, the Company may, from time to time, enter into physical fixed-price sales contracts in order to manage its exposure to fluctuations in commodity prices and foreign currency exchange rates. The following is a summary of natural gas physical fixed-price sales contracts in effect as at December 31, 2005, that has fixed future sales prices (fixed natural gas prices are based on the AECO "C" and NIT Index):

Daily quantity	Remaining term of contract	Fixed price per GJ	Approximate equivalent price per mcf
6,000 GJ/d	January 1 to March 31, 2006	CA$13.21	CA$14.53
6,000 GJ/d	April 1 to October 31, 2006	CA$9.77	CA$10.75
6,000 GJ/d	November 1 to December 31, 2006	CA$10.84	CA$11.92

NOTE 10 SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital, excluding bank debt:

	2005	2004
Accounts receivable	$ (12,450)	$ (3,539)
Prepaid expenses	6	(275)
Accounts payable and accruals	29,247	2,969
Change in non-cash working capital	**$ 16,803**	$ (845)
Relating to:		
Operating activities	$ 398	$ (5,703)
Investing activities	16,405	4,858
Change in non-cash working capital	**$ 16,803**	$ (845)

During the year, the Company made the following cash outlays in respect of interest expense and capital taxes:

	2005	2004
Interest expense	$ 972	$ 653
Capital tax	150	246

BOARD OF DIRECTORS

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OFFICERS

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David C. Morgenstern
Vice President, Exploration

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2 Member of the Audit Committee
3 Member of the Reserves Committee
4 Member of the Compensation Committee
5 Member of the Disclosure Committee

HEAD OFFICE

Suite 500
505 Third Street S.W.
Calgary, Alberta
Phone: 403.201.9153
Fax: 403.201.9163
T2P 3E6
www.celticex.com

REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
Suite 310, 606 Fourth Street S.W.
Calgary, Alberta
T2P 1T1

LEGAL COUNSEL

Borden Ladner Gervais LLP
1000 Canterra Tower
400 Third Avenue S.W.
Calgary, Alberta
T2P 4H2

BANKERS

National Bank of Canada
Suite 2700, 530 Eighth Avenue S.W.
Calgary, Alberta
T2P 3S8

AUDITORS

PricewaterhouseCoopers LLP
Suite 3100
111 Fifth Avenue S.W.
Calgary, Alberta
T2P 5L3

EVALUATION ENGINEERS

Sproule Associates Limited
Suite 900
140 Fourth Avenue S.W.
Calgary, Alberta
T2P 3N3

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading symbol "CLT"

ABBREVIATIONS

bbls	*barrels*
mbbls	*thousand barrels*
bbls/d	*barrels per day*
BOE	*barrels of oil equivalent*
mBOE	*thousand barrels of oil equivalent*
BOE/d	*barrels of oil equivalent per day*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
bcf	*billion cubic feet*
mmcf/d	*million cubic feet per day*
mmbtu	*million British Thermal Units*
GJ	*gigajoules*
AECO-C	*Alberta Energy Company "C" Meter Station of the Nova Pipeline System*
API	*American Petroleum Institute*
ARTC	*Alberta Royalty Tax Credit*
CICA	*Canadian Institute of Chartered Accountants*
WTI	*West Texas Intermediate*

CONVERSION OF UNITS

Imperial = *Metric*
1 acre = *0.4 hectares*
2.5 acres = *1 hectare*
1 bbl = *0.159 cubic metres*
6.29 bbls = *1 cubic metre*
1 foot = *0.3048 metres*
3.281 feet =*1 metre*
1 mcf = *28.2 cubic metres*
0.035 mcf = *1 cubic metre*
1 mile = *1.61 kilometres*
0.62 miles = *1 kilometre*
1 mmbtu = *1.054 GJ*
0.949 mmbtu=*1 GJ*
Natural gas is equated to oil on the basis of 6 mcf = *1 BOE.*

CELTIC'S ANNUAL GENERAL MEETING OF SHAREHOLDERS IS SCHEDULED FOR WEDNESDAY, APRIL 26, 2006, AT 3:00 P.M., TO BE HELD AT THE METROPOLITAN CENTRE, 333 FOURTH AVENUE S.W., CALGARY, ALBERTA.

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MANAGEMENT TEAM (LEFT TO RIGHT)
Michael R. Shea, David C. Morgenstern, David J. Wilson, Sadiq H. Lalani, Alan G. Franks

Celtic Exploration Ltd.
Suite 500, 505 Third Street S.W.
Calgary, Alberta T2P 3E6